GETEM -Geothermal Electricity Technology Evaluation Model

<u>Background:</u>

GETEM was originally developed for the Department of Energy's Geothermal Technologies Program to provide both a method for quantifying the power generation cost from geothermal energy, and a means of assessing how technology advances might impact those generation costs. Generation cost is determined as the Levelized-Cost-of-Electricity (LCOE). The model is intended to provide representative estimates of cost and performance for geothermal produced from scenarios defined by a User, and not as a tool for assessing specific projects or sites. In its current form it is more amenable to a project specific evaluation; however its intended purpose remains the more generic assessment of geothermal power production.

<u>General Layout:</u>

The input for the model is generally arranged by the phases of a geothermal project. The layout on the *Input* sheet is summarized here:

- Economic Parameters
- Exploration
- Confirmation
- Well Field Development
- Reservoir Definitions
- Operation and Maintenance
- Power Plant

The model has a ***Summary*** sheet that has the same layout as the ***Input*** sheet. Information on both sheets is 'grouped' so that it can be expanded or collapsed as the User desires. This allows the User to more readily peruse the input and calculated results for a given project phase without having to scroll up or down in what are otherwise lengthy worksheets.

At the top of the ***Input*** and ***Summary*** sheets is a block of cells that identify the scenario being evaluated, and display both the LCOE and the power sales which update as the input is changed. Both have a Reference Scenario and an Improved Scenario. The User defines the Reference Scenario and then inputs a multiplier that is applied to a particular input parameter to represent a technology change. For instance if the cost to drill a production well was $1,000,000 for the reference scenario and one wanted to see what the impact on LCOE from reducing that cost by 20%, one would input a multiplier of 0.8 in the appropriate cell, and the effect on cost of power of having $800,000 production wells would be displayed at the top of the ***Input*** sheet, as well as on the ***Summary*** sheet and the ***Binary Output*** and ***Flash Output*** sheets.

Results are displayed on the ***Summary*** sheet and the ***Binary Output*** and ***Flash Output*** sheets. The 'Output' sheets display summaries of the different contributors to the LCOE, as wells as their capital costs. Note that one cannot evaluate both a binary and flash conversion system simultaneously and view the results on these Output sheets. The model makes several calculations based upon the type of

conversion system selected, and cannot perform concurrent calculations for both conversion systems. Nor does the model allow for the simultaneous assessment of both hydrothermal and EGS resources.

The model includes an *Error-Warnings* sheet that summarizes issues associated with the input provided by the User. A count of the number of Errors and Warning Messages is given at the top of the *Summary* and *Input* Sheets. If one goes to the *Error-Warnings* sheet, a message will be displayed for any current error/warnings and a link provided to that section of the *Input* sheet containing the input in question.

In addition to these sheets, 5 others will typically be present. The *GETEM – Read Me* sheet contains general information about the model. The *Tables* has the Producer Price Indices that are used by the model. One can update these as desired; this sheet is protected, but not password protected. The *Binary A1* sheet has the macro that can be run to solve for the plant performance that minimizes the LCOE. It must be displayed ("Unhide") if one elects to use this option. The *IRR Economics* work sheet performs a discounted cash flow to project the project's internal rate of return (IRR) for either the calculated LCOE or a cost of electricity provided by the User. The *COE Economics* sheet calculates the cost of electricity (COE) needed to achieve a User defined internal rate of return (IRR).

The remaining sheets are typically hidden. These sheets are where the calculations are made or have data used in those calculations. The User can opt to "Unhide" if desired.

The following is a format that is generally used within the model:
- Cells with Yellow background are cells where the User provides input.
- Cells with Red font are imported from other worksheets within the file
- Cells with Light Pink background indicate those sections of the input where the User has defined a technology improvement
- "note" adjacent to an input cell indicates there is a comment having information relevant to that input cell

For certain inputs, the User must select from a drop down list. This list must be used in order for the model to decide how to proceed with the calculations. In some instances all the options in the drop down list will be the same – this is because the option does not apply for either the resource or conversion system being used. To the left of some input cells there is a drop down list for the units in which the input is being provided. The choice of units is limited to facilitate the units conversion to those used in the model calculations (Imperial).

Methodology:

Estimates are based upon the scenario the User defines by providing input for the each of the project phases. A User can define scenarios for either Hydrothermal or EGS resources, and for either air-cooled binary or flash-steam conversion systems. Calculations will be based upon either a targeted Power Sales or a fixed number of production wells.

In characterizing the resource, its temperature and depth are defined; with EGS resources the User has the option of using the earth's temperature gradient to define either the depth or temperature of the resource.

In defining the Exploration phase, the User establishes whether or not exploration wells will be drilled. (It is possible that no exploration wells would be drilled if the scenario being evaluated is the expansion of a project that is already producing power.) If wells are drilled, it is assumed that the project moves to the Confirmation phase when the 1st successful exploration well is drilled. The success rate (inverse of number of wells drilled) is a metric that DOE can adjust in assessing how advances in exploration technology can impact costs. The model has been revised to allow the successful exploration well to support production during the operation of the power plant, provided it is a production-sized well. The User defines the non-drilling exploration costs by activity, or provides a lump sum to represent these costs.

In the Confirmation phase, the User identifies number of successful confirmation wells that will be drilled prior to moving to the final Well Field Development phase. The model allows a User to define this well count, or to define the portion of the production capacity that must be confirmed before one moves forward with the project development. Production capacity is the total produced flow that is needed for the power plant. Successful confirmation wells are always assumed to be production wells that support the plant operation. It is assumed that the wells drilled during the confirmation phase will be more expensive than those drilled during the final phase of developing the well field. The model estimates drilling costs during that final phase; the User defines a multiplier ($\geq$ 1) to establish the confirmation well drilling cost. When an EGS resource is evaluated, the successful confirmation wells should be stimulated – the User provides that cost.

In characterizing the Well Field Development phase, the User must define how the well drilling costs are to be determined for both the production and injection well, as well as the number of injection wells and whether any dry holes or spare wells are drilled. The model calculates the cost of the surface equipment (piping, valves, vessels, etc.) for each well, or the User can provide that cost.

The costs to stimulate a well are identified by the User. The User also defines the flow rate per well, the hydraulic drawdown, and the thermal drawdown. The flow rate per well, well depth and hydraulic drawdown are used to establish the geothermal pumping power required per unit mass flow of geothermal fluid. These calculations include friction losses for the fluid flow in both the production and injection wells.

The power plant performance metric used is the brine effectiveness, or specific output. It is the net power produced from the plant per unit mass flow rate (net power is exclusive of geothermal pumping, but includes losses associated with fan and pumping power within the plant conversion system). Once the User establishes the conversion system type and provides the input necessary to define this metric, the project size and cost are determined.

If the scenario being evaluated is based on a specific Power Sales, the amount of flow required to produce these sales is

$$Total\ Geofluid\ Flow\ = \frac{Power\ Sales}{(Plant\ Brine\ Effectiveness - Pumping\ Power\ per\ unit\ mass\ flow)}$$

The number of production wells required is the total flow required divided by the flow rate per well, and the number of injection wells is this number of production wells multiplied by the ratio of injection to

production wells (User defined). The Well Field Development phase costs are determined using the well count and the costs per well for drilling and the surface equipment. The well count is the number of injection wells required and the number of production wells drilled during this phase (the number of production wells required less the successful confirmation and exploration wells), as well as any spare wells and dry holes identified by the User. The surface equipment costs are based on the total number of production and injection wells required, plus any spare wells identified by the User.

The power plant size needed to support this level of sales is the product of the total flow rate and the plant brine effectiveness. The plant cost is determined based upon this size, the plant design temperature and the plant brine effectiveness. If there is any geothermal pumping power, the plant size will be larger than the targeted power sales.

Operating labor costs are estimated based upon the type of conversion system being used and the plant size. Maintenance costs are estimated as a % of the capital costs for the plant and the well field. Pump maintenance costs are based upon the type of pump being used (User defined).

As indicated, the User also defines the thermal drawdown for the resource. For hydrothermal resources, in particular those used with air-cooled binary plants, the expectation is that the resource temperature will decline at rate of 1% per year, or less. (For a 0.5% decline rate, a 200°C resource's temperature would drop by 1°C the first year of operation.) It is postulated that the temperature will decline more rapidly in an EGS resource. If so, at some point the power produced by the plant will decrease to a level where it is not feasible to continue operation. To account for this, the model triggers the replacement of the entire well field at a point in the future when the temperature decline has become excessive. The maximum temperature decline allowed is calculated, or the User can opt to input the temperature decline allowed before reservoir replacement. Again, when then the temperature drops below the minimum allowed, the model replaces the entire well field – it does not drill one or two additional wells, but all the wells. This is done to simplify the model's determination of the effect of the temperature decline on power output. The number of times that the well field and reservoir can be replaced is based upon the power plant size and the resource potential that is found by the exploration activities. If 100 MW of potential is found and the plant size is 40 MW, the field and reservoir can be replaced once. If the final well field and reservoir replacement occurs before the end of the 30 year project life, the resource temperature and plant output continue to decline. No well field and reservoir replacement is allowed during the last 5 years of the project life.

The determination of the LCOE is based upon the power sales and the utilization factor that the User defines. The utilization factor is the ratio of the kW-hrs that is produced annual to that produced if the plant had operated continuously throughout the year at its design output. The utilization factor accounts for the output lost during outages, as well as the impact of the ambient air temperature on the plant output. DOE typically uses a value of 95% for this factor; there is discussion of this factor and the value used in the original GETEM manuals. The inputted value is indicative of the impact of the ambient on output at the design condition. In order to account for the impact of the resource temperature decline, the power sales are predicted at one month intervals at the resource temperature that is determined for each period based on the temperature decline. Sales at each interval is determined using the available energy (for binary plants the sink temperature is 10°C), the 2nd law conversion

efficiency, the geothermal flow rate and the geothermal pumping power. If the decline reaches the maximum allowed, the well field is replaced and the geothermal fluid temperature returns to the original value, as do the power sales. The calculated sales are discounted at a User defined rate over the assumed 30 year project life. The discounted sales are summed over the project life, along with the discounted sales from a plant operating at the design output for the same period. The ratio of these two totals (predicted to design) is then applied to the inputted Utilization Factor to correct it to reflect the effect of the declining resource temperature. This corrected factor is referred to as the 'Levelized Utilization Factor'. It is used with the design Power Sales to calculate the levelized total power sales for a year; that value is used in calculating the LCOE.

With EGS the User is also prompted to provide the temperature for which the power plant design is to be based (for hydrothermal resources, the plant design temperature is always the initial well head temperature). This feature allows the User to examine the impact of a designing the plant for a lower temperature as a means of offsetting the postulated higher temperature decline rates for EGS resources.

Once the input has been provided for the Exploration, Confirmation, Well Field Development, Reservoir Definition, and Operation & Maintenance activities, the User has the option of allowing the model to determine the level of binary plant performance that minimizes the LCOE. If the model performs this optimization, a trade-off is made between the cost of the plant (which varies directly with plant performance) and the cost of the well field and reservoir (which vary indirectly with the plant performance). For each defined scenario, there is a level of plant performance that produces this minimum generation cost. If this option is not used, the User must provide the plant performance as an inputted brine effectiveness. The determination of binary plant cost is based this performance metric. Neither performance nor cost is specific to a particular working fluid. The plant cost is based on the net plant power (turbine generator output less in-plant parasitic), which is the sum of the power sales and any geothermal pumping power. The turbine-generator cost is based on an estimate of the net plant output and an estimate of the in-plant parasitic power. This parasitic load estimate is based on the brine effectiveness.

For flash-steam conversion systems, the model estimates the optimal flash pressures based upon the resource temperature and the number of flash pressures identified (1 or 2). Note that this estimate approximates the conditions that produce the maximum power – the User will likely be able to achieve lower LCOE varying the flash pressures slightly from the values the model calculates. The model can be run with no geothermal pumping. This will allow flashing to occur in the well; this option is intended to be used with the flash steam plants and not the binary plant. The model estimates the well head pressure, and if it is less than the estimate of the optimal 1st stage flash pressure, the model defaults to well head pressure for the 1st stage flash. The model's estimate for the 2nd stage (low pressure) flash pressure defaults to a value 1 psi above atmospheric pressure if the calculation of the optimal value is less than one atmosphere. If the User inputs a flash pressure that is outside of this range (1 atmosphere and the well head pressure), an Error-Warning message will be displayed. Note that while the model's estimates for the optimal flash pressures are displayed, the User must input the flash pressures that the

model eventually uses. This is necessary in order to prevent 'Circular References' when flash conversion systems with no pumping are used in an EGS scenario.

The model's projection of binary plant performance is based upon the premise that there is a minimum temperature limit placed on the geothermal fluid leaving the power plant. This limit is based upon the solubility of amorphous silica. This limit can be placed on the flash plant – if so, it does account the increased concentration of silica in the unflashed geothermal fluid. The estimate of the 2nd stage flash pressure will default to a value that prevents silica precipitation if the calculated optimal pressure would is less. If not placed on the flash plant, it is assumed that the User will account for the added chemical cost to prevent scaling from the geothermal fluid.

Once the LCOE has been determined, the User can utilize the economics portion of the model to either project an internal rate of return for the project based upon the LCOE (or a cost of electricity provided by the User), or to determine the cost of electricity needed to provide a desired internal rate of return.

Limitations:

The model does not have default values for the different resource types or different conversion systems.

The Producer Price Indices are from the Bureau of Labor Statistics and should be updated by the User to provide estimates outside of those years currently in the model (1995-2010).

With a Hydrothermal resource, the model assumes the power plant is designed at the resource temperature less the estimated temperature drop in the production well; there is no provision to assess costs at other design temperatures with this resource type.

Binary power plants are air-cooled. Flash plants use evaporative heat rejection systems that utilized condensed steam for makeup water; with EGS resources this water loss is included in the calculation of the makeup water cost.

Though in reality successful confirmation and exploration wells could be utilized as injection wells, in the model they are always assumed to support fluid production for the power plant and decrease the number of production wells that must be drilled during the Well Field Development phase.

In calculating the casing configuration in the well, the model assumes the conductor casing at the surface cannot exceed a diameter of 48-inch. It also assumes that the minimum diameter for the upper casing interval in a production well is 13-3/8 inch. This constraint is imposed to assure sufficient clearance for a production pump. The constraint is imposed in all production wells, even if not pumped. The model also assumes the upper casing diameter cannot exceed 16 inches for both production and injection wells.

The binary power plant performance and cost are based upon modeling results for geothermal temperatures between 75° and 200°C. The model will predict outside of those temperatures, however the User should be aware that those temperatures represent scenarios that are beyond the model's capabilities.

The costs for the binary plants are based on sizes that are 3 MW and larger. Smaller plants are outside the range of the cost data used in developing the model's cost correlations.

The binary plants for which cost and performance correlations were derived have single vaporizer pressures, i.e., dual boiling cycles were not evaluated. These plants were however allowed to operate at supercritical pressures with a wide range of heat exchanger pinch points. It is believed that it is unlikely that dual-boiling plants would provide significantly lower costs than those estimated at equivalent levels of performance.

For binary plants, both cost and performance correlations were developed with a temperature constraint imposed of the geothermal fluid leaving the plant to prevent silica precipitation. The removal of this constraint is not an option for binary plants, as it is for flash-steam conversion systems.

Previous version of the model included an option to change the tube material (and cost) in the geothermal heat exchangers. This option became inactive when the method of applying the PPI's was modified. The model now defaults to always using carbon steel tubes in the geothermal heat exchangers.

The scaling of turbine costs ($/kW) with size has the largest impact of any of the plant equipment on the variation in binary plant costs ($/kW) with size. The cost correlations have an inherent assumption that the maximum size for a binary turbine is 15,000 hp. Once the turbine for the plant reaches this size, the turbine cost ($/kW) is constant. Plant costs continue to decrease with increasing size, however the rate at which costs decrease is diminished.

The water properties that are used in the calculations are based upon curve fits of those for saturated water. These curve fits were developed using water properties to provide estimates that were with 0.1% of those predicted using NIST properties for temperatures up to 500°F (260°C). The effect of salinity on the water properties is not included in these calculations. The correlations used continue to provide reasonable approximations of water properties at temperatures up to ~575°F (300°C). It is recommended that GETEM not be used to evaluate flash plants at higher temperatures. In evaluating those scenarios, the User should provide input for both plant performance and cost.

When the resource temperature declines to the maximum value specified, the entire well field is replaced and that cost incurred. The model does not allow for drilling one or two wells to offset the temperature decline either by increasing temperature or flow produced to the power plant.

The model predicts the effect of a varying resource temperature on power output after a plant has been installed. As the resource temperature deviates from the plant design temperature there is increased uncertainty in the levels of power predicted. The calculation of plant output with the varying resource temperatures always assumes that the total fluid flow to the plant is constant.

The determination of the LCOE is based upon annual levelized costs for the well field makeup costs. These annual costs for the well field makeup are effectively spread over the entire project. Though two royalty rates are included in the User input (reflecting the current BLM royalty structure), the model uses an effective royalty rate of ~2.9% over the entire project life. The option for the discounted cash flow analysis does account for both royalties and well field makeup costs at the time when they are incurred. Annual plant and well field O&M costs are assumed to be constant in that analysis.

Modifications to the Model:

Originally the model considered only hydrothermal resources. It has subsequently gone through several revisions. In these revisions, the emphasis has been primarily for the air-cooled binary conversion system. The modifications include the following:

- Inclusion of EGS (Enhanced Geothermal Systems). To accommodate EGS, the model
    - Allows the User to provide input defining the well stimulation costs
    - Production fluid temperature based on the Carslaw-Jaeger solution for conduction from a semi-infinite solid. This solution requires the User define a fracture system.
    - Predicts production pumping power using the bottom-hole pressure in the injection well rather than hydrostatic pressure.
- Costs estimates are adjusted using the Department of Labor's Bureau of Labor Statistics Producer Price Indices (PPI) for equipment, labor, and well drilling. The PPI's allow costs from varied sources to be incorporated and adjusted to the year that is of interest to the User.
- Provision to use both SI and Imperial units for input (the model calculations are done primarily in Imperial units).
- The effect of the production fluid temperature decline on plant power output is estimated. In order to account for this impact when determining the LCOE, the power estimates are discounted at a User defined rate. The power that would be produced if the plant operated at its design output is also discounted over the life of the plant. The ratio of the total discounted actual power to the total discounted design power is applied to the utilization factor; this 'levelized utilization factor' is then used in determining the annual power sales for the LCOE calculation.
- A maximum allowable temperature decline was integrated into the model that triggers the replacement of the geothermal well field if exceeded. This decline rate was derived from the end-of-operation temperatures in EPRI's *Next Generation Geothermal Power Plant* report (see original GETEM manuals). The values used represent a decline of ~10% in the Carnot efficiency at the well field replacement.
- The effect of having to replace the well field at a future date is included in the LCOE. This is done by discounting the number of times the well field is replaced and multiplying that value by the current well field costs (including successful confirmation and exploration wells, well stimulation, surface equipment and pumps) to establish a present value of these makeup well field costs. This value is treated as a capital cost in the LCOE determination.
- Production pump setting depths are calculated as a function of well flow rate, casing sizes, well depth, resource temperature and hydraulic drawdown. This change was made to better assess the benefits of improvements in production pump technologies and in well stimulation to increase reservoir permeability and reduce hydraulic drawdown.
- Injection pumping power is calculated using the same parameters. This change was made in order to more accurately reflect the impact of changing the number of injection wells relative to the number in production wells.

- Binary power plant costs are determined as a function of the plant performance, as well as resource temperature and plant size.
- The prediction of the staffing for the operation and maintenance of the plant and field was changed from a step function with size to a continuous function of plant size. This was done to eliminate the increases in the LCOE that occurred when the plant size changed slightly and produced a step change in the plant staff size.
- An estimate of the temperature drop in the production well was included that is based on a technique described by Ramey (1962). This temperature drop is a function of the bottom-hole temperature in the well, the well depth, the earth temperature gradient, properties of the earth surrounding the well, well casing/liner size, cement thickness, the well flow rate, and time. The model assumes that the temperature loss in the well reaches a quasi-steady state level after one year. This provision was included to better characterize the temperatures produced from deep wells having lower flow rates.
- An estimate of transmission line cost is provided. This cost is based on the line voltage, distance, population setting and terrain.
- A suite of exploration methods/tools was added to the model. Once a User opts to utilize a method listed, the User then decides whether to use the model's default cost for the selected methodology. The User also has the option of whether or not to proportion the exploration costs by the ratio of the net plant output and the resource potential. If the user opts to do so, exploration costs are spread among the current project and future projects. It is recommended that this option not be used with EGS resources. The user also has the option of including unsuccessful exploration projects costs in the cost of the current project.
- An alternative method for determining well drilling costs has been added to the model. This was done to allow the effect of using different hole sizes for the injection and production wells to be evaluated. Of specific interest is whether the additional cost associated with a larger injection wells is offset by the potential to drill fewer injection wells and/or reduced injection pumping requirements. It may also allow DOE to examine the effect of technology improvements (for example, bit life and rates of penetration) if it can be shown to provide representative well drilling costs. This has yet to be confirmed.
- Two economic worksheets have been added. One performs a discounted cash flow analysis to determine the internal rate of return for a given sales price for electricity. This cost of electricity can be either that calculated by GETEM using the fixed charge rate, or one provided by the User. A second worksheet determines the cost of electricity needed to yield an internal rate of return defined by the User.
- An option was included to allow the successful exploration well to provide fluid to the power plant. This requires all exploration wells to be production well sized. This well is treated as a successful confirmation well in the model's determination of cost associated with the Confirmation and Well Field Development phases.

Model Input:

The User defines the scenario to be evaluated. Again there are currently no default values in the model so the User must go through the input to assure that the values that are already in the model represent the scenario. As indicated, provide input in those cells with Yellow backgrounds. The User is advised not to make changes outside of the highlighted cells.

The input is 'grouped' both by the phase of the project (i.e., Exploration, Well Field Development, O&M, …), as well as by activities during the phase (i.e., drilling activities and non-drilling activities during Exploration). The grouping allows the input sections to be expanded and collapsed. This grouping allows the User to 'skip' those sections that are not relevant to the scenario being defined. For example, it one opts to use a flash-steam conversion system, there is no reason to expand the binary plant input as none of that input is used in the model's calculations. Generally conditional formatting is used to 'white out' those sections of input that are not relevant based on the User's input. The model uses drop down lists for input in deciding how calculations will be made; this input is also the basis for most of the conditional formatting.

The *Summary* sheet has project phase grouping similar to those on the *Input* sheet. The *Summary* sheet summarizes both the input and results for the project phases. Once the input has been provided to define a specific scenario, one can review results on the *Summary* sheet and return to the appropriate section on the *Input* sheet to adjust as necessary. In some instances the results in one section will be dependent upon the input in another section. For instance, the production pump setting depth that is calculated is a function of the well depth and fluid temperature, the hydraulic drawdown in the reservoir, and the well diameter(s).

The final input section relates to the determination of power plant performance and cost. This is done because the model contains a macro that uses the relationship between binary power plant performance and its cost to determine the level of performance that minimizes the LCOE.

Information is provided for some of the input via comments located adjacent to those cells. The comments are revealed when the cursor is place on the cell containing the word "note". In Appendix 1 of this document there are suggested values for selected input for Hydrothermal and EGS scenarios. These are suggested values; if the User has information/data that is specific to the scenario being evaluated, that information/data should be used. This is not a complete listing of the input to the model.

The following provides further description of the model input.

Economic Parameters - These are parameters used in the calculation of the LCOE. Input includes:

- General Parameters:
    - Year of Estimate – determines the PPI's that are applied to capital costs. The model has PPI's from 1995 to 2010
    - Utilization factor – the ratio of kW-hrs produced annually to the kW-hrs that would have been produced if the plant operated 24 hrs/day for the entire year. This utilization factor is

for performance at the design plant temperature – it includes the effect of varying ambient temperatures, but not the decline in resource temperature.

- o Contingency – applied to all calculated capital costs; it is indicative of project risk and uncertainty
- o Royalty – BLM rate is 1.75% for 1st 10 years and 3.5% thereafter. For the LCOE calculation, an average royalty of 2.92% is used.
- o Discount rate – this is the rate used to discount the future power production and future costs for well field replacement (if necessary). It is used to account for the effect of the resource temperature decline on the LCOE.
- o Fixed Charge Rate –this value is multiplied by the project capital costs to determine the annual cost of capitalized equipment and services. It includes rate of return to equity and interest on debt, income taxes, property taxes, and insurance. The value used in the original model was 0.128. This value was used in the EIA NEMS runs for the Annual Energy Outlook 2005 report. The value currently being used in the EIA NEMS runs is 0.108. The original GETEM manuals include a discussion of this factor and what it includes

- Project Duration: Input in this section is used for the discounted cash flow analysis. The User provides time durations for different project phases. It is assumed that confirmation follows immediately after exploration, and that the well field development (including stimulation) and power plant construction proceed concurrently once the confirmation phase is completed. The time for plant construction should always be equal to or greater than that for well field development. If different time intervals are provided for these 2 phases, the model assumes they start at the same time, and the well field development is completed first.
- General Economic Conditions: This input allows the User to evaluate either the IRR for the project based on the model's calculated LCOE or a cost of electricity provided by the User, or to determine the cost of electricity needed to achieve a specified IRR. The model's estimates of capital and operating costs and the power output over the project life are used in calculating these economic parameters.

Resource Definition- In this input section the type of resource is defined. For Hydrothermal resources, the resource temperature and depth are inputted. For EGS resources, the User has the option of defining both depth and temperature, or basing either on a defined earth temperature gradient.   The information provided is used to establish the performance of the power plant, which is based upon a 'design' temperature (defined in the Power Plant Input). The upper limit for this design temperature is the production fluid temperature, which is calculated as the initial resource temperature less the fluid temperature drop in the well. This temperature drop is determined using an approach described by Ramey (1962) as a function of well flow rate, depth, well casing and cement, the earth temperature gradient, and rock/soil properties around the well. Though the temperature loss in the well changes with time, at some point it becomes quasi-steady state, which is the value used in the model (based on a time period of 1 year).

Exploration - Input for the exploration phase includes definition of the general parameters for the activity, the information needed to both determine the number of wells drilled and their cost, and the costs associated with the non-drilling activities. The User is asked to define the initial resource status;

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this input is used in assessing the logic for the subsequent input - it does not directly impact cost. The User also defines the potential resource found by the exploration activities. This value is used if the User opts to proportion the exploration costs, i.e., spread the costs over several projects. It is also an important input for evaluating scenarios with more rapid thermal drawdown as it determines the number of times a well field can be replaced. It is recommended that if an EGS resource is being evaluated, that the exploration costs not be proportioned with the resource potential found. One can also include the costs of unsuccessful exploration projects. If the User opts to include those costs, a success rate for exploration projects must be defined. The costs for an unsuccessful project are assumed to be the same as those for the current project.

- Exploration Drilling Costs:
    - If exploration wells are drilled, the User must define either the number of exploration wells drilled or the exploration drilling success rate. If a success rate is used, the number of wells drilled is the inverse of the success rate. If the User indicates no wells are drilled for a Greenfield project, a warning will be displayed. One can proceed with the evaluation, but the warning will not clear.
    - A User defines whether slimhole wells will be used for Exploration. The wells must be either slimhole or production sized; they cannot be a combination of slimhole and production sized wells. If production sized wells are to be drilled after drilling slimhole wells, those full-sized wells should be included as confirmation wells, not exploration wells.
    - A User defined multiplier is applied to the calculated well cost for the defined depth. This multiplier allows for non-production sized (diameter) wells to be drilled – slimholes. It is recommended that a multiplier of 0.6 (or larger) be used for slimhole wells; if wells are production sized, multiplier should be >1
    - Well costs are defined using one of the GETEM well cost curves.
    - The user defines the ratio of the exploration well depth to resource depth (allows for a different exploration well depth). This depth is used with the well cost curve and cost multiplier to define well cost.
    - If the wells are production sized, the User identifies whether the successful exploration well will support plant power production. If the wells are slimhole, the model will not use the successful exploration well to supply fluid to the plant.
- Exploration – Non-drilling Costs:
    - Exploration costs not associated with well drilling can be defined as an inputted lump sum or by activity.
    - Activities include:

Method	Tool	Default Cost
Survey of existing information		$32,000
Field Work	Reconnaissance and sampling	$48,000
	Water and gas sample analysis – geothermometry	$4,000
	Rock & soil analysis	$3,000
	Soil Flux Analysis	$4,000

	Fluid Inclusion Stratigraphy	$7,500
Analysis of Field Structure		$80,000
Remote Sensing	Multispectral Imaging	$139,000
	Hyperspectral imaging	$62,500
	LiDAR	$115,000
	Aerial Photography	$1,500
	FLIR	$15,000
Geophysics	Gravity	$40,000
	Aeromagnetic	$115,000
	2D Seismic	$45,000
	3D Seismic	$135,000
	Vertical seismic profiling in well	$150,000
	Single borehole and cross well seismic	$75,000
	Direct current/resistivity	$40,000
	Self Potential	$30,000
	Electromagnetic	$200,000
	Magnetotelluric	$150,000
Temperature Gradient	Drill gradient holes	$75,000
	2-meter probes	$34,500
Interpretation and reporting		$96,000
Other	Technical and office support	12% of exploration costs

- o User defines activities to be used and either accepts default cost or inputs revised cost for method/tool used.
- o Note that the default costs are assumed to be 2010 costs. They've not yet been tied to a Producer Price Index. The Bureau of Labor Statistics has a discontinued PPI for Oil and Gas drilling Exploration Services; a current data base has not yet been found for this cost category.

Confirmation – The model assumes the project moves to the confirmation phase once the first successful exploration well is drilled (if wells are drilled during that phase). All wells drilled during this phase are assumed to have the same construction as production wells. Successful confirmation wells are subsequently used to support power plant operation.

- Confirmation Well Drilling Costs
    - o Success rate represents the fraction of confirmation wells drilled that can subsequently be used to provide production to the power plant.
    - o The number of confirmation wells that are drilled is defined by the User, or is based on the % of the fluid production capacity that must be confirmed during this phase of the project. If a production capacity of 50% is required, then sufficient successful confirmation wells must be drilled to provide 50% of the geofluid flow required by the plant. The production capacity per well is based on the plant performance, geothermal fluid pumping power and the flow rate per well. Note that if exploration wells are full sized wells and a User opts to

use the successful exploration well to provide fluid to the plant, the count of successful confirmation wells needed to confirm production capacity is reduced by 1.

- o Confirmation well cost is based upon the calculated production well cost and a multiplier defined by the User. This multiplier should always be ≥ 1, reflecting the higher drilling cost during the initial stages of a project.
- Confirmation – Non-drilling Costs
    - o Confirmation costs not associated with drilling are either inputted as a lump sum or calculated as a % of the total confirmation costs.
    - o If an EGS project, the 'successful' confirmation wells should be stimulated. The User provides the cost per well for the stimulation. The model requires 2 successful confirmation wells for this stimulation. The count of successful confirmation wells stimulated includes the successful exploration well if the User indicates this well will be used to support fluid production to the power plant.
    - o Well testing is based on the User's defined count of well tests and the cost per test. It is believed that the number of wells tests should be equal to or exceed the number of successful confirmation wells drilled.

Well Field Development – In this phase, the User provides input necessary to define costs per well, surface equipment costs and establish the number of injection wells. The User can also identify the number of wells drilled in this phase that are not successful, or are used as spares. Note that a project can be evaluated based upon the number of successful production wells (this includes successful confirmation and exploration wells), or on a targeted power sales at the design condition. The User provides this information in the input for the power plant. If the project is based upon power sales, the number of production wells required is determined by the flow per well, the plant performance, geothermal pumping power and the desired power sales.

- Well Field Details
    - o Spare wells are drilled as part of the initial well field development to provide reserve flow capacity in the future. Dry wells are unsuccessful wells that cannot be used for either production or injection. The effect of using the spare wells at a later date is not included in the projections of outyear power production.
    - o The ratio of production well depth to resource depth allows for drilling beyond the resource depth. This ratio should always be ≥ 1.
    - o The ratio of the injection well to production well depths allows for drilling injection and production wells to different depths.
    - o The ratio of injection to production wells defines how many injection wells are required. The number of injection wells is based upon the total number of production wells required (which includes successful wells drilled during the confirmation and exploration phases).
- Well Drilling Costs
    - o Opt to use either the Cost Curves built into GETEM or a methodology that estimates the drilling cost based on the well configuration and user information relative to bit life, rates of penetration, etc..

- o The 3 Cost Curves (Low, Medium, and High) bracket the Sandia National Laboratory drilling data (see GETEM reference manuals). These costs are updated from 2004 using the Producer Price Index for drilling Oil and Gas Wells.
- o GETEM's Estimate requires the User define
  - ▪ The configuration at the bottom of both the production and injection well
    - • whether the production/injection interval is open hole or perforated/slotted liner
    - • the hole diameter or casing OD in the production/injection interval
  - ▪ This input is used to establish the well's casing/liner configuration based upon assumptions relative to the cement thickness, casing diameters and commercial bit sizes. The model has two constraints on the maximum casing size – one for the conductor casing and the other for the upper casing interval. If the User input for the bottom hole diameter results in an estimated casing sizes that exceed either maximum value, the User is prompted to use a smaller bottom hole diameter. The model also always assumes that production wells have upper casing diameters of 13-3/8 inch or larger in order to accommodate a production pump and casing.
  - ▪ The method has embedded values for determining time for different drilling activities and costs. The User can adjust those values by changing the multiplier/index for Trouble, Rate of Penetration, Bit Life, Casing Cost, and Cement Cost. These indices are applied to all intervals in the well. The Trouble multiplier/index is applied to the total estimated rig time for each identified activity, and is reflected in the costs for that activity, as wells as the total time to drill the well.
- o The User can adjust the well cost estimates produced by either method.
- • The User can opt to provide the surface equipment costs as a lump sum value per well, or can allow those costs to be calculated based upon the inputted distance from the well to the plant and the maximum pressure drop allowed. This calculation is based upon the assumption that geofluid is a liquid in the surface piping.
- • Other costs during the Well Field Development phase are determined as a % of the total costs for this phase. The User provides that % value.

Reservoir Definition – In this section the User defines the 'performance' of the reservoir. This includes the flow rate for each production well, and information relevant to the hydraulic and thermal drawdown. In this section the User also defines the well stimulation cost and the subsurface water loss in EGS reservoirs. Hydrothermal resources can be stimulated, however the model always assumes that the total production and total injection flow rates are equivalent for Hydrothermal resources (EGS resources have higher injection flows in order to makeup the subsurface losses, which are defined by the User). Well flow rate and hydraulic drawdown dictate the calculated production pump depth and associated power requirement. The thermal drawdown establishes the production fluid temperature decline with time. The model assumes that there is a maximum limit for this decline, and that once this limit is reached the entire well field is replaced. This maximum decline limit is calculated by the model, or the User can input a value. The number of times that the well field replacement can occur is

dependent upon the resource potential determined during the exploration phase (a User input). The model estimates the power produced by the plant as the temperature declines. This power output is used to adjust the utilization factor in the determination of the LCOE.

- The cost to stimulate a well can be inputted or can be calculated; it is recommended that it be inputted. If calculated, the model requires the User to define a subsurface fracture system and the cost per unit surface area required to create the fracture system (cost varies linearly with the size of the reservoir created). This option is intended to allow a User to perform a trade-off between the stimulation cost and the thermal drawdown. At this time the 'calculated' costs are entirely conjecture based on the User's input.
- Unless the User has information specific to the reservoir (permeability, height, fracture system created, etc.), it is recommended that the User opt to input a Hydraulic drawdown rate rather than use the model's determination of the drawdown. If the User does not have data that provides a drawdown rate, it is suggested that a rate of 0.2 to 0.6 psi per 1,000 lb/hr be used for Hydrothermal resources. There is little information upon which to recommend a value for EGS reservoirs. Data from wells drilled by DOE in the Basin and Range during the 1970's had drawdown rates of ~0.8 psi per 1,000 lb/hr. These wells had relatively low permeabilities; it is postulated that EGS reservoirs will have similar or higher drawdown rates. When using the model's kA method to estimate drawdown and the User has kH information, use a width of 1 (with units consistent with the kH data).
- It is recommended that the Annual Decline Rate be used to characterize the thermal drawdown; it must be used for Hydrothermal resources.
- If the user opts to calculate the thermal drawdown, the model utilizes the Carslaw-Jaeger solution for transient conduction from a semi-infinite solid. This approach requires the User provide information relative to the number of fractures created, the fracture width and aperture, and the distance between the wells (used as the fracture length). The model has properties for rock that the User can change. Note these rock properties only affect the transient heat conduction solution – they are not used in determining well costs.
- It is postulated that there will be water losses in EGS reservoirs. The model estimates the impact of these losses on the LCOE based upon the User's input of the % of the injected flow that is lost and the unit cost of the makeup water. If the User uses a flash-steam plant with an EGS resource, the model estimates the water required for the evaporative heat rejection and includes that water consumption in this makeup water cost (this is always done for Flash-EGS scenarios regardless of the User input).

Geothermal Pumping – This input section is used to identify how the geothermal pumping power and pump costs are to be determined. Again if the model calculates the pump setting depth, those calculations rely on the input provided for Reservoir Definition (flow and drawdown), Resource Definition (temperature and depth) and Well Field Development (casing configuration).

In providing the input for EGS resources, scenarios can be defined that create 'Circular References' in the model. These references arise because of how the model determines the pressure at the bottom of the production well. With Hydrothermal resources, this pressure is based on a calculated hydrostatic

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pressure. With the EGS resource, the geothermal fluid is assumed to be a 'closed loop' and the bottom hole pressure in the production well is a function of the pressure of the fluid as it enters the reservoir in the injection well. For the model to work, this closed loop must have a defined pressure at some point. If a production pump is used, the minimum pressure needed at the pump suction provides that pressure. With a flash plant using an EGS resource, the User defined flash pressure provides the defined pressure required; this allows for the analysis of a scenario without production pumping for an EGS flash plant.   If input produces a 'Circular Reference' that the User cannot resolve, please contact Greg Mines (Gregory.Mines@inl.gov, or 208-526-0260)

- The User defines whether the wells are pumped. Unless the well flow rates are low, it is likely that when the binary conversion system is used pumps will be required. Note that if the model's calculation determines no production pumping is needed, the pump setting depth defaults to 0. If a flash-steam conversion system is used, the model allows flashing to occur in unpumped wells. The model estimates a surface pressure and requires that the 1st flash pressure be lower than this well head pressure. If flashing does occur, a warning/error message displays. If flashing occurs with a binary plant, a second warning/error message is displayed.
- If the pump depth is calculated, the User must identify the excess pressure at the pump suction. This value is effectively the NPSH for the pump, and includes the pressure required to keep non-condensable gases in solution. This same excess pressure is required at the production well head, and must be provided by the pump (the excess pressure accounts for surface pressure losses between well and plant).
- The User also identifies the ID for the production casing and provides a surface roughness for the casing (0.00015 ft is recommended – from Crane Technical Paper 410).
- If the well costs are determined using the Cost Curves, the User must define the bottom hole well diameter and whether the production interval is open hole or has slotted/perforated casing. This information is used to estimate the production well casing configuration used to determine friction losses in the well
- The User inputs the type of production pump used – either Submersible or Lineshaft (there is a limit on the setting depth for 2,000 ft). This input is used in determining the O&M costs for the pump; it does not have any impact on the calculated pump costs.
- The User decides whether to use the model's calculated production pump cost or to provide that cost. The calculated cost requires that the User define the casing and installation costs for the pump; the model estimates the pump cost based on the calculated horsepower. The User can adjust the calculated cost.
- The injection well pumping power requires the User provide information relative to the binary conversion system and surface piping pressure loss (recommend a value of 30 to 50 psi). This information and the production well head pressure are used to establish the injection well head pressure. If a flash-steam conversion system is used, the model uses the lowest flash pressure as the injection well head pressure.
- If the well costs are determined using the Cost Curves, the User must define the bottom hole injection well diameter and whether the injection interval is open hole or has slotted/perforated

casing. This information is used to estimate the injection well casing configuration, which in turn is used to estimate friction losses.

- The model's calculation of the injection pumping power is based upon having a downhole pressure that exceeds the hydrostatic pressure by 1 psi. The model prompts also prompts the User to identify whether the reservoir pressure buildup is to be included in the determination of the injection pumping power. This buildup is analogous to the hydraulic drawdown in the production well and it is recommended that the User input 'Yes".   When included, the minimum bottom hole pressure required in the injection well is the hydrostatic pressure plus the reservoir buildup pressure plus 1 psi. The model displays the excess pressure at the bottom of the well. If the value is negative, injection pumping is included; if desired, the User can include additional excess pressure, which will further increase the pumping power.

Operation and Maintenance – The model's calculations for Operations and Maintenance (O&M) are based in part upon the experiences of the original developers of GETEM, which suggested that O&M costs for conventional hydrothermal plants (including the well field) were between 1 and 3 ¢ per kW-hr. Based upon those experiences and discussions with plant operators (primarily binary plants) regarding the significant contributions to O&M, a methodology was developed to estimate the O&M costs. Labor is a major contributor to the operations cost; the methodology used defines the O&M staff based on both conversion system type and plant size. Maintenance costs are defined as a % of the capital costs for both the plant and the well field. Costs are also included for maintenance of the geothermal pumps. (The power for these pumps is not considered an operating expense; rather it is subtracted from the net plant output to establish the Power Sales, which is used to determine the LCOE.) The User can adjust (decrease) the plant staffing to reflect the use of increased automation in operating the plant. Operators represent ~50 to 60% of the total plant staff, with the remainder for maintenance, engineering, management and office personnel; operators are assumed to also perform some maintenance activities. If the User elects to significantly reduce staff, then the % assigned for the maintenance costs should be increased to reflect the higher cost associated with contracting for maintenance in lieu of maintaining staff to perform those activities.

- The User opts to use either the model's calculated O&M costs or provide those costs (¢ per kW-hr) for both the power plant and the well field.
- If the O&M costs are calculated, a fraction of the operator time is assigned to the well field (suggest 25 %). Labor rates are also identified for staff – default values are given, which the User can change. The total predicted staffing level is displayed – the User can adjust this total. The adjustment is applied to all staff categories.
- The annual maintenance costs for the well field and surface equipment (outside of the plant boundary) is determined as a % of the total capital costs.
- The User can also provide input to define costs to treat the geothermal fluid. Binary systems are less likely to have these chemical costs. They are more likely to be incurred with flash plants. It is unknown what they might be for EGS resources.
- The annual maintenance costs for the power plant are determined in a similar manner – as a % of the plant capital cost.

- For flash plants, the User should identify the chemical costs associated with the evaporative heat rejection system. The model estimates the cooling water flow needed and establishes the cost based on a dosage and chemical cost ($/gallon) (both are User inputs).
- The production pump maintenance is based upon the type of pump used. The User must identify the probable pump life: based on prior discussions with operators it is expected that lineshaft pumps will have a longer operating life than submersible pumps. The model calculates the pump cost (the model cost calculation does not differentiate between the pump types) and a cost to remove and install a pump. The User can use these costs or provide costs. When lineshaft pumps are specified, the User also needs to provide input for the cost for the oil used to lubricate the shaft between the pump and the motor (located on the surface).

Power Plant – As part of the Power Plant input, the User indicates whether transmission lines will be included in the LCOE determination. If so, then input is provided to determine that cost. The User defines the whether the conversion system is air-cooled binary or flash-steam, and identifies whether the LCOE will be based on the Power Sales or the Number of Production Wells required. The Power Sales is at the design temperature for the power plant, which the User must specify.   The User can either define the plant performance (brine effectiveness) or allow the model to determine the plant performance that minimizes the LCOE. The model uses the plant performance to establish the capital cost for the plant. If the model determines the performance, it trades off the effect of the plant performance on both the plant and well field costs until a minimum LCOE is achieved. For scenarios with shallow, productive wells, the optimal plant performance will be lower. As well depth increases and/or reservoir productivity decreases, the optimal plant performance will increase. This optimization is performed with a macro that uses the Excel Solver Add-In (see Appendix 2 for instructions regarding this add-in). The flash-steam plant performance is based upon the flash pressures that are inputted by the User. The model estimates optimal flash pressures based upon the resource temperature; those values are displayed immediately below the User input. Major components are sized and their costs estimated based upon those sizes. The model estimates the direct construction cost based on these equipment costs, and the installed cost based on the User input for indirect costs.

- If the User elects to include transmission costs, inputs are required both from drop down lists to establish the line voltage, terrain and population density, and to establish the distance for the transmission line. These inputs are used to establish the transmission line cost ($/mile). The costs and the approach used were developed from a PG&E presentation made in 2009. They do not include costs for substations.
- The User defines whether the LCOE determination will be based on Power sales or the number of production wells (exclusive of dry holes or spare wells) and defines the number of units, i.e., is 15 MW of sales coming from one 15 MW unit or three 5 MW units. Note the number of units defined should not drop the output per unit below ~3 MW (to assure that the costs predicted are within the size range for which the equipment correlations are based).
- The User defines a design temperature for the plant. If a Hydrothermal resource is being used, the model defaults to the production fluid temperature (resource temperature less the temperature loss in the well). For an EGS resource, the model suggests a design temperature. For binary plants the suggested value is the production fluid temperature less ½ the maximum temperature declined

allowed; for flash plants the value is the production fluid temperature. It is probable that the User can vary this design temperature from the suggested value and provide a lower LCOE. The optimal value is dependent upon several factors, including the thermal decline rate and the rate at which future power sales are discounted (User input).

- The User selects the conversion system to be used in the analysis: air-cooled binary or flash-steam.
- Binary Plant Input
  - The User establishes whether the plant performance is going to be inputted or calculated. If inputted, the model lists the maximum plant performance (brine effectiveness) for which plant costs have been estimated. This maximum is based on the plant design temperature.
  - If performance is to be calculated, click on the CALCULATE box. This is a hyperlink to sheet **Binary A1**. On this page enter a value in the cell with the yellow background that is less than the maximum displayed (suggest about half that value) and click on the red button. A box with the Solver results will be displayed. If a solution is found, click OK to accept the results. In lieu of using solver, one can manually change the plant performance in the cell with the yellow background till an optimal value is found. (This manual changing of the performance metric to minimize the LCOE can also be done on the **INPUT** sheet if the User opts to input this metric.) Once completed click on the RETURN box to return to the **Input** sheet.
  - The next section of input is to define the plant cost for the reference scenario. The model uses the plant performance, plant size (net plant output – not power sales), and the design (or resource) temperature to estimate the costs of the major components in the plant – the turbine-generator, air-cooled condenser, geothermal heat exchanger and working fluid pump. The model defaults to using carbon steel tubes in the geothermal heat exchanger. (Prior versions of GETEM allowed the tube material to be varied and the associated impact on costs reflected in the heat exchanger cost; this feature has not been integrated back into the model though plans are to do so.) The User can adjust these equipment costs.
  - The model applies a multiplier to these equipment costs to determine the direct construction costs. The multiplier that the model determines includes other equipment installed as part of the plant construction, steel, 'other' materials, labor (including fringe and benefits), and consumables (including rentals). The PPIs are used to adjust the contributions from each to the total multiplier. This multiplier also includes the User defined freight and tax (both applied to non-labor costs). The calculated multiplier is displayed – the User can opt to use this value or input a value.
  - The indirect costs for the plant construction are defined by the User as either a fixed value or as a % of the direct construction cost. These indirect costs include costs for engineering, home office, management and supervision, permitting, etc..
  - The User must define how the plant cost for the improved scenario is to be defined relative to the reference scenario. If the plant cost ($/kW) is reduced, the User must provide that decrease relative to a plant having the same performance; this may require that the User redefine the reference scenario so that its plant has the same performance as that for the improved scenario. If the plant performance is improved, then one must establish how the plant cost is going to change with that improvement. Note that the model's optimization of performance is dependent upon how one defines the project scenario (power sales or fixed number of

production wells); slightly different levels of optimal performance will be obtained for each project type even though the number of wells may be very similar. Regardless, the change is small and if the improvement is to provide any advantage relative to current technologies, the cost for the improved plant ($/kW) should be lower than what the model estimates for that level of performance. If the improved plant's cost is based upon its performance, a multiplier is provided that allows the User to adjust that cost downward. This allows one to assess how much additional improved plant cost (relative to the reference plant) can be tolerated before technology producing the performance improvement no longer provides a reduction in the LCOE.

o The binary plant input also allows one to assess the footprint of an air-cooled binary plant. If determines that foot print based upon the estimated size of the air-cooled condenser and the User defined ratio of the total plant footprint to that of the air-cooled condenser.

- Flash-Steam Input
  o The model allows the design ambient conditions to be varied in the determination of the flash plant performance. The User identifies these ambient conditions.
  o The User also identifies the isentropic efficiencies of the turbine and pumps, as well as the generator efficiency.
  o Plant performance is based upon the flash pressures. The User must identify whether there will be a temperature constraint place on the geothermal fluid leaving the plant and establish whether there will be 1 or 2 stages of flashing. The model will estimate the optimal flash pressures (those producing the maximum power); those estimates are displayed. The User can opt to input those values or to use other flash pressures. Note that it is probable that the User will be able to adjust the pressures and produce a higher output and lower LCOE; however these increases are not anticipated to be significant. If the inputted high pressure flash pressure exceeds the estimated production well head pressure, a warning will be displayed
  o The User must define the pressure drop between the flash vessel and the turbine.
  o The User must define the condenser type and provide input relative to the cooling water temperature rise, pinch points (approach temperatures) in the condenser and cooling tower, the cooling water pump head and the non-condensable gas partial pressure in the condenser. For the different condenser types, the pinch point in the condenser will vary, as well as possibly both the cooling water pump head and cooling water temperature rise.
  o Hydrothermal resources contain varying levels of non-condensable gases that come out of solution when the fluid flashes and pass through the turbine to the condenser with the steam. These gases must be removed from the condenser or they will adversely affect plant performance. The User defines the level of non-condensable gases in the geofluid, including the level of hydrogen sulfide (H_2S). The model assumes hydrogen sulfide must be abated, and uses this concentration to estimate the capital cost of the abatement system. The User also defines how the non-condensable gases are to be removed, the number of stages in the removal process, and if a vacuum pump is used, its efficiency.
  o In order to estimate the cost of the equipment the User defines the steam condenser heat transfer coefficient. This value is used to estimate the size of all the surface condensers (the model assumes that surface condensers are used in the non-condensable gas removal system).

The maximum droplet size is also inputted. This droplet size is used to calculate a terminal velocity, which is used with the steam flow rate to establish the diameter of the flash vessel and its cost.

o   Similar to the binary cost model, estimates are provided for the major components in the flash-steam plant. The User can adjust these estimated costs.

o   The model applies a multiplier to these equipment costs to determine the direct construction costs. The multiplier that the model determines includes other equipment installed as part of the plant construction, steel, 'other' materials, labor (including fringe and benefits), and consumables (including rentals). The PPIs are used to adjust the contributions from each to the total multiplier. This multiplier also includes the User defined freight and tax (both applied to non-labor costs). The calculated multiplier is displayed – the User can modify.

o   The indirect costs for the plant construction are defined by the User as either a fixed value or as a % of the direct construction cost. These indirect costs include costs for engineering, home office, management and supervision, permitting, etc..

Determination of Internal Rate of Return (IRR) or Cost of Electricity

Once the LCOE has been determined, the User can use that value and the estimated capital and operating costs to determine the project's IRR. This is done on the ***IRR ECONOMICS*** sheet. On this sheet a macro finds the IRR that produces a net present value of 0 for the discounted cash flows. This analysis assumes that a project is starting today, and discounts the subsequent capital costs incurred during the project development, as well as the subsequent revenue and cost streams. Capital costs for each project development phase are discounted from the mid-point of the interval assigned for that activity. The revenue streams are based on the estimated plant output each year, taking into account the impact of a declining resource temperature. It is assumed that the costs after plant startup are the estimated O&M costs, Royalties (based on revenue stream), and those costs associated with any necessary replacement of the well field and reservoir. In lieu of using the LCOE, the User can provide a cost of electricity, and the IRR is calculated for that value.

A similar methodology is used on the ***COE ECONOMICS*** sheet to determine the cost of electricity for a User defined IRR.

Appendix 1

Suggested Input values for Hydrothermal and EGS resources

Input Parameter	Hydrothermal	EGS
ECONOMIC PARAMETERS		
General Project Variables :		
Utilization Factor	90 to 95%	
Royalty (thru Yr 10)	1.75% (BLM)	1.75% (BLM)
Royalty (after Yr 10)	3.5% (BLM)	3.5% (BLM)
Project Schedule & Durations :	3-5 yr	
RESOURCE DEFINITION		
Earth Temperature Gradient	NA	see SMU maps
Average Ground Temperature @ Surface	NA	10-15C
Resource Temperature	binary ≤200C; flash <300C	
Resource Depth	<3km	
RESOURCE EXPLORATION		
Exploration Parameters:		
Are Exploration costs to be proportioned based on Potential Resource?		No
Exploration - Drilling Costs :		
Will Exploration Wells Be Drilled ?	Yes for Greenfield projects	
Success Rate	20 to 40%	
Multiplier for Exploration Well Costs	0.6 for slimholes; >1 for production sized wells	0.6 for slimholes; >1 for production sized wells
Exploration - Non-Drilling Costs :		It is postulated that there will be minimal cost associated with the Exploration for EGS. The heat is present in the subsurface. It is anticipated that perhaps some temperature gradient holes will be required, as well as some limited use of one or more of the exploration tools/methods typically used with hydrothermal resources. Both would be used to site the production-size wells that would subsequently be drilled.
By Activity :	see GEA reports	
Survey of Existing Information	Yes	
Field Work		
Field Reconnaissance and Sampling	Yes	
Water & Gas Sample Analysis, including geothermometry	Yes	
Rock & Soil Sample Analysis	Yes	
Soil Gas Flux Analysis		
Fluid Inclusion Stratigraphy		
Structural Analysis	Yes	
Remote Sensing		
Multispectral imaging	One of these two	
Hydperspectral imaging		
LiDAR		
Aerial Photography	Yes	
FLIR		
Geophysics	Yes	
Gravity	Yes	
Aeromagnetic	Yes	
2D Seismic Reflection / Refraction		
3D Seismic Reflection / Refraction	Yes	
Vertical Seismic Profiling (in well)		
Single Borehole and cross well seismic		
Direct Current / Resistivity	Yes	
Self-Potential		
Electromagnetic		
Magnetotelluric	Yes	
Temperature Gradient Measurements	Yes	
Drill Temperature Gradient holes		
2-meter probes		
Interpretation and Reporting	Yes	
Technical & Office Support (% of Exploration Costs)		

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Input Parameter	Hydrothermal	EGS
RESOURCE CONFIRMATION		
Confirmation Well - Drilling Costs :		
Confirmation Well Success Ratio	> rate than defined for exploration drilling	likely higher than for Hydrothermal
Production Capacity to be Confirmed	maybe as high as 50%	likely > than Hydrothermal
Multiplier for Confirmation Well Costs (>= 1)	should be >1; suggest 1.2 or higher	should be >1; suggest 1.2 or higher
Confirmation Well - Non-Drilling Costs :		
Percentage of Confirmation costs	see GEA reports	
Are Confirmation Wells to Be Stimulated ?		Yes
Stimulation Cost		$2,000,000
Well Testing	Yes	Yes
Well Testing Cost per test	see GEA reports	see GEA reports
WELL FIELD DEVELOPMENT		
Well Field Details:		
Number of Dry Wells (Unusable as Injectors)	>0	
Ratio Injection Well to Production Well Depth		1
Well Drilling Costs :		
How are costs for drilling wells determined ?		
Cost Curves	Recommended	Recommended
Cost Curve to be used for each Well Type		
GETEM Estimates		
Adjustments to Production and Injection Well Drilling Costs :		
Other Field Costs :		
How are surface equipment costs determined ?		
Fixed Cost		
Calculated Cost		
Average distance from well to plant	<1 km	
Maximum pressure drop in Surface Piping	binary ≤20 psi; flash <5 psi	
RESERVOIR DEFINITION		
Well Flow Rate		
Production Well Flow Rate - 'typical'	>60 kg/s	<80 kg/s
Well Stimulation		
How are well stimulation costs determined ?	Input value	Input value
Input Fixed Stimulation Cost per well		$2,000,000
Calculated	Use only if trying to assess tradeoff between stimulaiton cost and reservoir performance	
Hydraulic Drawdown		
How is Hydraulic Drawdown determined?	recommend input value	recommend input value
Inputted drawdown rate	0.4 psi/1000 lb/hr	0.8 psi/1000 lb/hr
Calculated:		
kA		
Reservoir Permeability (k)		
Reservoir Height		
Reservoir Width	if kH data available, set width to 1	if kH data available, set width to 1
Thermal Drawdown		
Use This Maximum Allowable Temperature Decline?	recommended	recommended
How is Thermal Drawdown Determined ?	annual decline rate	annual decline rate recommended
Annual Rate of Decline	0.50%	anticipate higher rate for EGS
Water Loss		
Subsurface Water loss as % of injected flow (≥ 0)	0	5%

| Input Parameter	Hydrothermal	EGS
GEOTHERMAL FLUID PUMPING		
Pump Efficiency for production and injection pumping	60%	60%
Production Pump :		
Are Production Wells pumped ?	binary - yes	Yes
How pump depths are established ?	Calculate	Calculate
Calculation Pump Depth :		
Excess Pressure at pump Suction and/or well head	50 psi	50 psi
Inside diameter of production pump casing	8.535 inch	8.535 inch
Surface roughness for casing	0.00015 ft	0.00015 ft
Type of production pump used		
How is pump cost to be determined?		
Calculate Pump Cost :		
Casing cost	$45 ft	
Injection Pump :		
Surface Equipment ΔP for binary conversion system	40 psi	40 psi
Is reservoir pressure buildup included in determining injection pumping?	Yes	Yes
OPERATION & MAINTENANCE		
Input Annual O&M Costs or Calculate?		
Input the annual O&M Cost for the Power Plant	1- 2 cents/ kW-hr	1- 2 cents/ kW-hr
Input the annual O&M cost for the Field (including production pu	$\leq$ 1 cent/kW-hr	$\leq$ 1 cent/kW-hr
Operating Cost Calculation		
Labor Costs		
Fraction of operator labor assigned to field	25%	
Field Maintenance		
Annual Maintenance non-labor (fraction of field capitalcost)	1%	
Power Plant Maintenance		
Annual O&M non-labor (fraction of plant cost)	1-2%	1-2%
Geothermal Production Pump Maintenance		
Line shaft pump operating life	2-4 yr	2-4 yr
Submersible pump operating life	2-3 yr	2-3 yr
POWER PLANT		
Transmission Cost		
Power Plant Parameters		
Power Sales	Net Plant Output >3 MW	Net Plant Output >3 MW
Number of independent power units	constrained by minimum plant size	constrained by minimum plant size
Definition of Conversion Systems		
Is the Conversion System Flash or Binary?		binary
Binary Power Plant		
Plant Performance		
Use the calculated performance or input brine effectivene	recommend calculating unless User has defined performance	recommend calculating unless User has defined performance
Reference Scenario Plant Cost		
Major Component Costs		
Enter tube material cost multiplier	1 (carbon steel tubes)	1 (carbon steel tubes)
Direct Construction Costs		
Tax		
Freight	4%	4%
Use the calculated installation multiplier?	recommend using calculated	recommend using calculated
If No, input installation multiplier	$\geq$ 2	$\geq$ 2
Indirect Project Costs		
Are indirect plant costs determined as fixed value or % of direct construction cost?	recommend using %	recommend using %
Fixed Indirect Plant Cost		
Indirect Cost Percentage Multiplier	8 to 10%	8 to 10%

| Input Parameter	Hydrothermal	EGS
Flash-Steam Power Plant		
Plant Performance		
Component Efficiencies		
Turbine efficiency	80%	
Generator efficiency	98%	
Cooling water and condensate pump efficiency	705	
Flash Pressure		
Is a constraint placed on the GF temperature leaving pla	Yes	
Number of flashes		
Use calculated flash P's or input values	calculated	
Define Steam Pressure Drops		
Input pressure drop between high pressure flash and tu	1-3 psi	
Input pressure drop between low pressure flash and tu	1-2 psi	
Cooling System		
Condenser type		
CW pump head	60 ft	
Cooling Water temperature rise -DT,cw	30 F	
Pinch Point-condenser	10 F	
Pinch Point-cooling tower	5 F	
Condenser NCG partial pressure	0.5 inch Hg	
Non-Condensable Gas (NCG) Removal		
NCG level	0 - 2000 ppm	
Molecular Weight of NCG's	44 (air)	
H2S level	0 - 20 ppm	
Method of NCG removal		
Number of stages: ncg removal	1-3	
NCG vacuum pump efficiency	70%	
Flash-Steam Plant Cost		
Equipment Related Input		
Steam condenser heat transfer coefficient (U)	350 btu/hr-ft^2-F	
Max droplet size in flash vessel	200 micron	
Direct Construction Costs		
Tax		
Freight	4%	
Use the calculated installation multiplier?	recommend using calculated	
If No, input installation multiplier	≥ 2	
Indirect Plant Costs		
Input indirect plant costs as fixed value or % of plant total direct cost?	recommend %	
Inputted Fixed Indirect Plant Cost		
Inputted % Multiplier for Indirect Cost	8 to 10%	

Appendix 2

Solver Add-in:

Click on Windows Icon in upper left portion of screen, and select Excel Options (lower portion of the window)

Click on Addins (see below)
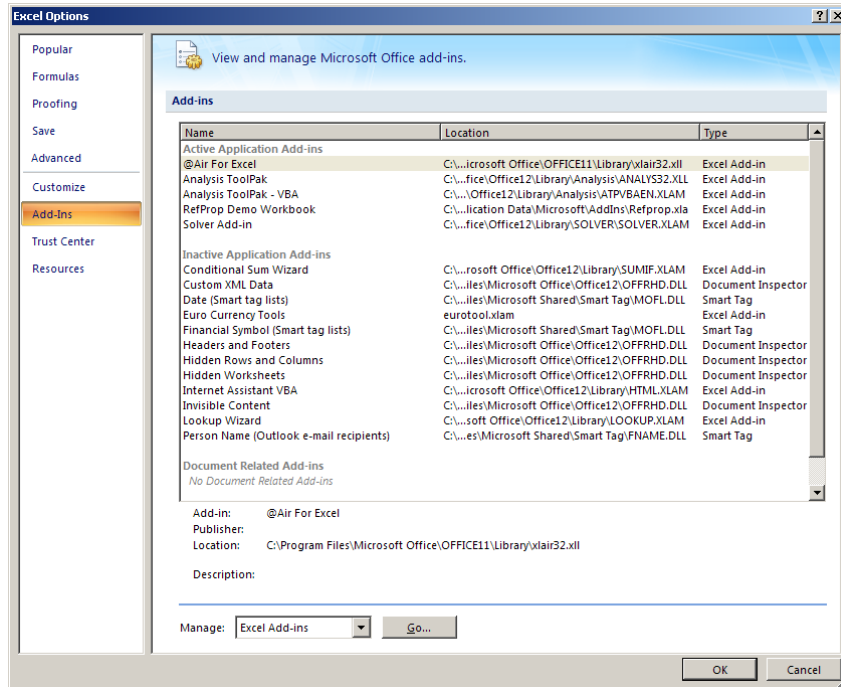
In the Manage window, select Excel Add-ins and click Go
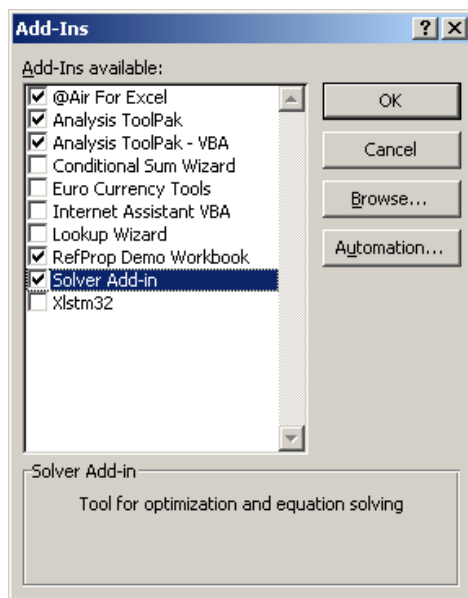
If the box next to Solver Add-in does not have a check, click on the box and once the check appears click OK. If solver does not appear in the listing, you will need to install the add-in. See Microsoft Help for instructions.

Once Solver has been added in, it will appear under the Data tab. This does not necessarily mean that the macros will be operational.

If the macros will not work, open the View tab and click on Macros, and then View Macros
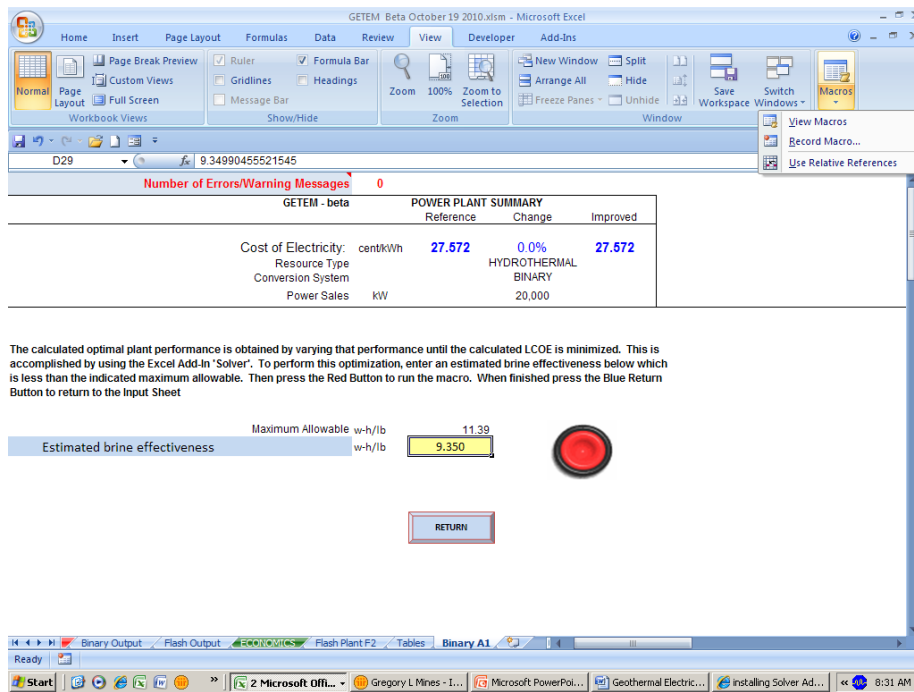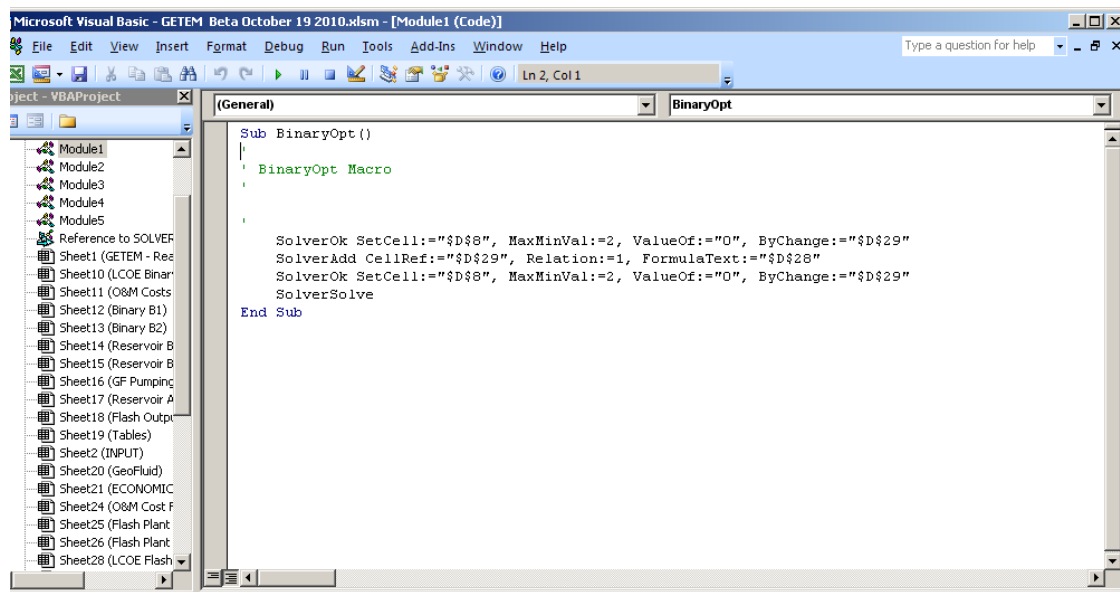

The following screen will appear. Select the macro and click edit
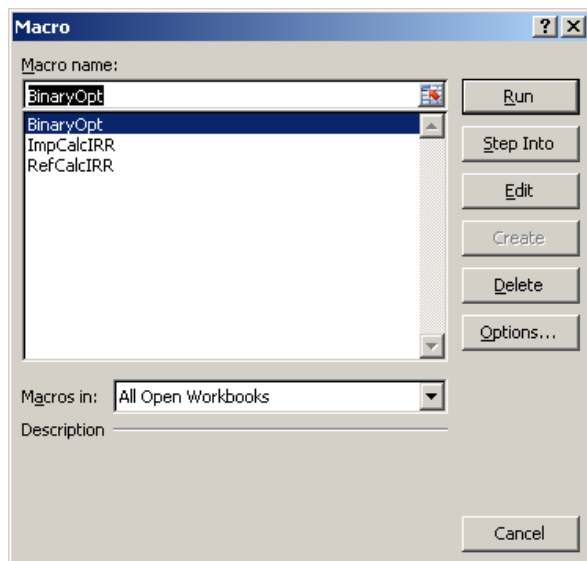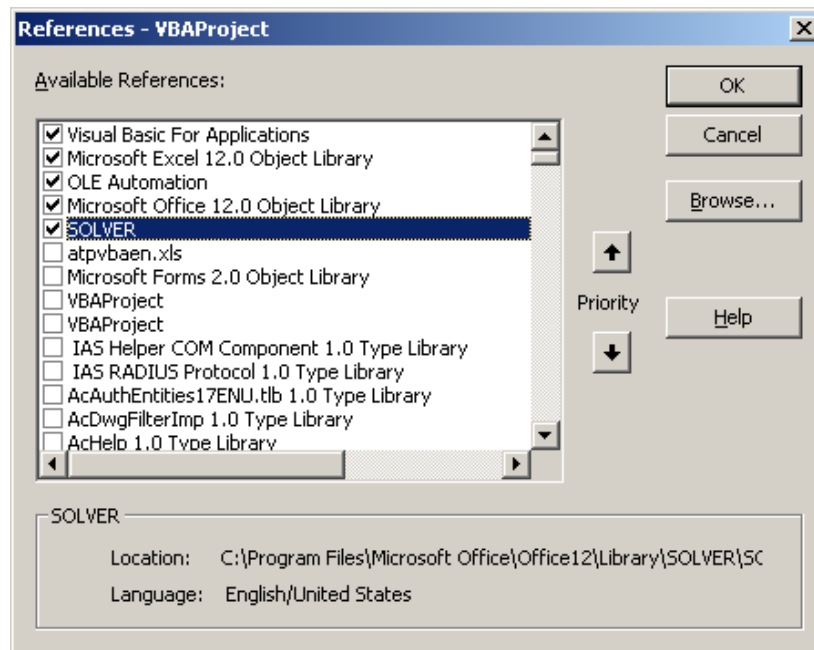
Draft

The following screen will appear. Click on Tools

and then References. The following screen will appear

Check the box next to Solver, then OK. Then close the visual basic editor and return to the Excel file

The macro should now work.